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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 12-IEP-1D
1516 Ninth Street
Sacramento, CA 95814-5512

Re: 2012 Integrated Energy Policy Report Update/Combined Heat and Power: Comments of Pacific Gas and Electric Company on Combined Heat and Power in California

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments in the California Energy Commission's ("CEC") 2012 Integrated Energy Policy Report ("IEPR") Update on estimates of combined heat and power ("CHP") technical and market potential in California. PG&E's comments will also respond to specific CEC questions on motivations and barriers to distributed CHP development and the implications of the Qualifying Facility ("QF")/CHP Settlement Agreement on existing and future CHP systems.

As California continues towards an ever-cleaner energy future, a critical issue is to understand under which circumstances CHP will actually reduce greenhouse gas ("GHG") emissions. PG&E's comments focus on how to measure these GHG reductions, the economic (as opposed to technical) potential for CHP, the need for new generation, the type of new generation needed (i.e., fast ramping to accommodate intermittent wind/solar generation), and who will pay the costs of new CHP. PG&E is concerned that the current analysis is not sufficiently robust to consider CHP in the broader framework of California's energy policies and whether CHP will help achieve California's energy and environmental goals. More analysis of these issues is needed.

To allow for easier review of PG&E's comments, the questions attached to the Workshop Agenda (as applicable to PG&E) are repeated below, along with PG&E's responses. PG&E is working to complete its responses to numerous questions and has indicated "To be provided" in response to certain questions where responses are still being developed. PG&E expects to provide these supplemental responses later this week.

PG&E is happy to discuss these comments with the CEC staff should additional information be needed. PG&E also provides a link to its January 12, 2012 presentation to CHP bidders. This presentation provides an overview on the CHP settlement, as well as the framework for PG&E's recently-issued CHP Request for Offer ("RFO").[1]

II. ICF'S REPORT OVERSTATES THE POTENTIAL FOR CHP

ICF presented an update to its 2009 assessment of the long-term market potential for CHP in California. While its current CHP estimates are lower – and more realistic -- than presented in 2009, PG&E believes that ICF's study continues to overestimate the potential for CHP in California, particularly for existing, small customers. PG&E was not consulted prior to the release of the ICF report and has had very little time to review it. Further, PG&E would appreciate the opportunity to provide more input prior to the CEC's use of the report to support IEPR conclusions and recommendations, and the company has identified several areas of the report that could be strengthened. Furthermore, PG&E notes that ICF's CHP adoption curves are very aggressive and, as a result, may overstate the potential to add CHP to the system, particularly in the current economic environment. Other assumptions used by ICF (e.g., assumed boiler efficiencies) may be too low and yield unrealistic adoption results.

Question 1: Are there major flaws in the assumptions or errors in the report that would have a significant influence on the findings?

Response 1:

Yes, as PG&E notes above, it has several concerns about ICF's assumptions about the technical and market potential for CHP in California. For example, ICF bases its technical potential analysis on usage patterns and business type, but ignores physical barriers such as space limitations or age of the building. ICF's assumptions on load factors and thermal usage do not reflect real-world analyses of CHP installations from the SGIP and QF programs. PG&E believes that the ICF methodology generally over-estimates technical potential.

ICF's market potential is based on economic drivers (price, rates and payback criteria) and ignores any non-economic factors, such as availability of air permits or zoning restrictions. Additionally, while the report is rich when describing the scenarios used, it provides little information on ICF's adoption modeling and it is, therefore, impossible to tell how the adoption curve works. Assuming ICF has used essentially the same the adoption curve methodology for the last three reports, and based on the difference between the predicted and actual adoption from the last two reports, PG&E suspects that the adoption curve overestimates adoption.

In addition to the concerns noted above, PG&E has identified one other significant concern with the ICF report -- the assumed boiler efficiency.

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1 http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/CHP/2012CHP%20RFO%20-%20Participants%20Conference%20Presentation.pdf

For boiler efficiency, ICF calculated the GHG benefit of CHP in both existing and new buildings by comparing it to a boiler of 80% efficiency. PG&E recommends that a higher boiler efficiency standard, at least 90%, should be used to estimate emissions from CHP in new buildings, because a developer's alternative is not an outdated boiler of merely 80% efficiency. Many firms now offer condensing boilers with efficiencies of 93% or better.[2] Given California's focus on GHG emission reductions (e.g., carbon pricing from California's cap-and-trade system), it is not clear that a boiler of just 80% efficiency would be a prudent developer's alternative to CHP at a new site.

Question 2: Using the various scenarios as a guide for outcomes of regulatory changes, what regulatory changes should the state pursue and why?

Response 2:

PG&E does not support additional regulatory changes at this time. Numerous initiatives have already been passed or authorized, and PG&E's focus today is on successfully implementing these policies. For example, PG&E's CHP Request for Offer ("RFO") is currently in process and the two of the three Assembly Bill ("AB") 1613 CHP power purchase agreements ("PPA") are now available. (The AB 1613 PPA for facilities less than 500 kw is under review at the CPUC.) Sufficient time should be allowed to implement these existing policies, and to gather "lessons learned" before layering on more initiatives that might actually increase uncertainty related to CHP development and operation.

Furthermore, PG&E urges the CEC to refrain from using the ICF report as support for any proposed regulatory changes. As discussed above, there has been insufficient time to review the report and the report's shortcomings call into question the validity of the conclusions. PG&E is also concerned as to whether the conclusions of the report are the result of an unbiased review of the issues. For example, the list of acknowledgements includes CHP advocates with an obvious stake in any outcome that will improve the economics for their constituents. It does not appear that any investor-owned utility stakeholder was consulted during report preparation. PG&E is concerned that this may have affected the tenor and results of the report itself. For example, the discussion of non-bypassable charges ("NBCs") fails to explain what they are, that they were established by the legislature, why they were established by the legislature, or any recognition that any cost avoided by a CHP installer is shifted to other customers. The statement on page 72 -- "As shown in Figure 17, Public Purpose Program Charges have increased by 25% since 2006 adding greater and greater burden on CHP customers" -- is patently one-sided. As the CEC knows, public purpose program charges support energy efficiency, low income energy

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A few examples, in alphabetical order: Noritz offers hot-water heaters at 93% efficiency (http://www.noritz.com/homeowners/products/view/ncc199_n_0841mc_series_condensing_tankless_water_heater/); Paloma offers 94% efficiency (http://www.palomatankless.com/products/condensing/specifications.html); Rheem offers the "Prestige" hot-water heaters at 94% efficiency (http://www.rheem.com/products/commercial/water_heating/tankless/); and Rinnai offers several condensing boilers at up to 95.7% efficiency (http://www.rinnai.us/boilers/).

efficiency, funding for research, development and demonstration ("RD&D"), support for emerging renewables, and other renewables subsidies. These funds have also helped CHP demonstration projects and analysis. In fact, PG&E anticipates incurring additional non-bypassable charges in support of the QF/CHP Settlement.

Another challenge is that the ICF report only analyzes how the proposed scenarios affect CHP adoption rates. Scenarios should be more broadly developed. Rather, the CHP analysis for California should consider:

- Under what circumstances does CHP reduce GHG? For example, according to Itron's 2010 evaluation of the SGIP program, the key findings for GHG and CHP were: 1) CO_2 emissions from non-renewable-fueled SGIP systems exceed CO_2 emissions from the displaced grid-based electricity; and 2) useful waste heat recovery operations act to reduce CO_2 emissions that would have resulted from use of on-site boilers.
- What changes to reporting protocols are needed to obtain existing measurements of used thermal output?
- How much will it cost to achieve GHG emissions reductions from CHP versus other choices?
- Who should bear the increased cost?
- Under what circumstances does CHP generation meet the requirements for the generation attributes identified in the long-term planning process?

Absent such an assessment, there should be no legislative recommendations. Legislative action should not be predicated on an analysis that ignores the cost, the rate impacts, the operating attributes of CHP, or the alternatives available to reduce greenhouse gas emissions.

However, if there are to be regulatory changes, preference should be given to projects that reduce GHG emissions while offering the most operating flexibility to accommodate electricity from intermittent generators. The 2011 Integrated Energy Policy Report ("IEPR") supports this preference, indicating:

"Grid-Level Integration: Maintaining reliable operation of the electric system with high levels of intermittent resources will require a variety of strategies including, but not limited to, regulation to follow real-time ups and downs in generation output, voltage, or frequency caused by changes in generation or load; ramping generation from other units to follow potential up or down swings in wind or solar generation; spinning reserves to provide standby power as needed; and replacement power for outages. System operators will also need strategies to address potential overgeneration issues that occur when there is more generation than there is load to use it…"[3]

[3] 2011 Integrated Energy Policy Report, p. 40, http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf

Question 3: Is use of the Scoping Plan's GHG reduction accounting method appropriate? If not, provide an alternative.

Response 3:

A. The focus should be on emissions, as well as emission reductions

ICF's GHG accounting is based on emission reductions. However, the actual level of emissions must also be measured. California's GHG goal is to emit no more than 427 million metric tons in 2020. That is an absolute value, not a "this unit emits less than that unit" accounting. While the Air Resources Board ("ARB") discussed emission reductions, not just emissions, in its AB32 Scoping Plan, compliance with the GHG goal will be determined by starting from zero, and adding physical emissions from all sources, rather than starting from some hypothetical case and subtracting emission reductions.

CHP in new buildings may reduce emissions compared to serving the new building's demands with grid electricity and separate boilers. However, the CHP will emit GHG. Those GHG emissions can be accommodated only by squeezing out some other GHG source, so that total GHG emissions are at or below 427 million metric tons in 2020.

The magnitude of CHP emissions can be roughly quantified. The QF/CHP Settlement Agreement sets a requirement of 3,000 MW, and Governor Brown's Clean Energy Jobs Plan calls for a total of 6,500 MW of CHP by 2030, or an incremental 3,500 MW above the QF/CHP Settlement level. As a hypothetical, assume that additional 3,500 MW is developed at new sites and used for on-site electricity demand, the new CHP would emit 17 million metric tons of CO_2e per year.[4] (This amount assumes the new CHP consists of 60 kW Tecogen CM-75E units or similar units at a capacity factor of 80%.[5])

Increases in GHG emissions are to be prevented by California's cap-and-trade program. Industrial or commercial expansion that involves GHG emissions will increase the demand for a fixed supply of GHG emission allowances, and thereby increase the "carbon price" to the extent necessary to curb GHG-emitting activities. Industrial and commercial expansion may well be beneficial, particularly if they create jobs, but under the cap-and-trade program, increased emissions in one sector must be offset by decreased emissions elsewhere.

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4 17 million metric tons/yr = 3,500 MW * 8,760 hrs/yr * 80% * 12.92 MMBtu/MWh * 0.05307 metric tons per MMBtu of natural gas.

5 Tecogen's CM-75E was chosen because it was featured in Slide 9 of Tecogen's presentation at the CEC's February 16, 2012 workshop, and operating specifications are available at the firm's website. Tecogen's presentation is at http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/presentations/06_Bill_Martini_Tecogen.pdf . Operating specifications for the 60 kW CM-75E are at http://www.tecogen.com/Collateral/Documents/English-US/CogenDS.pdf

Focusing on emissions, rather than emission reductions, will become ever more important as California's GHG emission targets decline. California's GHG emissions in 2008, the most recent year available, were 474 MMT. California's goal for 2020 is 427 MMT, or 90% of recent emissions. In 2050, the goal is 85 MMT, or 18% of recent emissions. Under ideal conditions, today the GHG emissions from generating 100 MWh of energy with CHP is about 70% of emissions from producing the same amounts of electricity and thermal output separately using current infrastructure. However, over time, with the retirement of aging, less efficient units and the introduction of more solar, wind and renewable generation, the benefit of CHP will erode because the system generation mix will become cleaner than it is today.

The table below presents current electric infrastructure, specifically, year-2010 operating data from a CEC report. PG&E added the "Subtotal" row, which shows an overall heat rate for California's gas-fired generation in 2010 (excluding CHP) of 7,577 Btu/kWh.[6]

California Natural Gas-Fired Power Plants Summary Statistics for 2010

Type	Capacity MW	Electric Generation GWh	Heat Rate Btu/kWh
New CCs	16,196	71,373	7,176
Aging plants	16,748	6,219	11,269
Peaker plants	4,331	848	11,202
Other	3,029	3,307	8,367
Total	40,304	81,747	7,577

Over time, the GHG emission rate of the electricity infrastructure is likely to decline as zero-GHG renewables are added to meet California's 33% Renewable Portfolio Standard. In addition, the next generation of combined cycle plants may be a dramatic improvement over the "New CCs" in the CEC data shown above. For example, General Electric's "FlexEfficiency50", recently slated for construction in France, is expected to achieve 60% efficiency, or a heat rate of 5,700 Btu/kWh.[7]

Two recent studies highlight this issue and have concluded that CHP does not play a role in California's achievement of the year-2050 GHG emissions goals.[8] In November 2009, Energy and Environmental Economics, Inc. ("E3") issued "Meeting California's Long-Term Greenhouse Gas Reduction Goals." The report is available at: http://ethree.com/documents/GHG6.10/CA_2050_GHG_Goals.pdf. The report presents four pathways to cut California's GHG emissions to 85 MMT in 2050. The electric generation mix in

6 Source: Table 2 of "THERMAL EFFICIENCY OF GAS FIRED GENERATION IN CALIFORNIA", available at http://www.energy.ca.gov/2011publications/CEC-200-2011-008/CEC-200-2011-008.pdf. The heat rate for CHP does "not incorporate a credit for the beneficial industrial use of waste steam" according to p. 2 of that report.

7 Source: http://www.ge-energy.com/products_and_services/products/gas_turbines_heavy_duty/flexefficiency_50_combined_cycle_power_plant.jsp 60% efficiency = 3412/0.6 or 5,700 Btu/kWh.

8 The two studies are cited and discussed on p. 6 of PG&E's comments in the 2011 IEPR proceeding: http://www.energy.ca.gov/2011_energypolicy/documents/comments_draft_iepr/PGandE_2011_Draft_IEPR.pdf

2050 is shown for each pathway in Figure 26 on p. 75 of that report. CHP is notable by its absence—no new generation from CHP occurs in any of the four pathways.

Furthermore, in the November 24, 2011 issue of Science, analysts from E3 and Lawrence Berkeley National Laboratory published "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity."[9] Like the earlier report, the November 2011 report has zero new generation from CHP. CHP was rejected explicitly as a measure that would become a stranded cost: "[Emission-reducing] measures were not selected if they would reduce emissions in the short term but would have to be retired before the end of their economic life in order to meet lower emissions targets in a later year." (p. 28)

These conclusions highlight the need to focus on actual emissions, not solely the emission reduction formula set forth in the ARB's Scoping Plan.

B. The Scoping Memo's CHP Efficiency and Capacity Assumptions Should be Updated to Capture More Realistic Assessments

To the extent it is valuable to review the Scoping Plan's emission reduction methodology, however, certain elements of the ARB Scoping Memo's methodology should be revisited and updated to reflect the development of CHP that has been observed in the marketplace. PG&E recommends that ICF review several recent reports issued by Itron, the California Public Utilities Commission ("CPUC"), and PG&E about the on-peak availability of CHP, assumed capacity factors, and efficiency.[10]

III. NUMEROUS POLICIES WILL AFFECT SMALL AND LARGE CHP PROJECT DEVELOPMENT

Question 1: What impact will Cap and Trade have on development of non-utility owned CHP? Would having a utility contract change the likelihood of development? How large a factor is the uncertainty of Cap and Trade prices in the decision to install a CHP unit?

Response 1:

California's cap and trade market will require fossil-fuel generating facilities that emit more than 25,000 metric tons per year to purchase compliance instruments equal to their CO_2 emissions. This new expense, which is a variable operating expense, will exert upward pressure

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9 The report is available for a fee, but the free "Supplemental Material" is available at: http://www.sciencemag.org/content/suppl/2011/11/23/science.1208365.DC1/Williams.SOM.pdf capacity.

10 Itron Reports: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm

Capacity Factors, see Table 10: http://www.cpuc.ca.gov/NR/rdonlyres/594FEE2F-B37A-4F9D-B04A-B38A4DFBF689/0/SGIP_CHP_Performance_Investigation_FINAL_2010_04_01.pdf

On-peak availability, see page 3-26: http://www.pge.com/includes/docs/pdfs/shared/newgenerator/selfgeneration/sgip_impact_report_2009_06-2010.pdf on wholesale electric commodity prices. It is widely viewed that California wholesale electric commodity prices will increase as a function of market heat rate (Btu/kwh), a natural gas emissions rate (MT/mmBtu) and an allowance price ($/MT) when this market begins.

All sellers of electricity can expect higher revenues than they would receive absent a cap and trade program. For all generation, if the emissions rate of their facility (MT/mmBtu) is less than the market's marginal emissions rate (a product of the market heat rate and emissions rate of natural gas), then that generating facility's operating margin will increase. If the converse is true, the facility's operating margin will decrease. CHP efficiency is measured by the double benchmark, which includes stand-alone boiler efficiency as well as the efficiency by which natural gas is converted to electricity.

For topping cycle natural gas fired CHP, operating margins will tend to increase for CHP facilities that operate more efficiently than the double benchmark, and may decrease for those CHP facilities that operate less efficiently than the double benchmark.

Increased energy payments are embedded in the energy payment structure of the QF/CHP Settlement for three years starting at the beginning of a cap and trade market, a "higher of" formula assures that market-based cap and trade compliance costs are included in energy payments. After this three year period, energy payments are based on electric wholesale market prices, which reflect market-based cap and trade compliance costs. All CHP facilities less than 20 MW that meet PURPA efficiency requirements have access to a QF PPA, which includes this energy payment structure.
(http://www.pge.com/includes/docs/pdfs/b2b/energysupply/qualifyingfacilities/settlement/final_term_sheet.pdf, Section 10, pp. 45-50.)

Question 2: Net-metering for CHP is restricted to fuel cells and projects that use biogas. Under these parameters, have there been any net metered CHP projects and what are they? Should net metering be expanded to apply to additional CHP technologies? If so, up to what capacity? Explain.

Response 2:

Net energy metering ("NEM") for CHP is confined to CHP using renewable fuel, regardless of whether it is a fuel cell or other technology. This benefit became available in 2012 and to date PG&E has received no requests from any CHP facilities to take advantage of the net metering program. PG&E is working to identify customers who may be CHP and who may be using renewable fuel. Should such customers be identified, PG&E will contact those customers to see if they would prefer NEM over their current tariff arrangement (such as NEMFC).

Net metering at retail rates should not be expanded beyond the existing program. PG&E supported the current net metering legislation, which is limited to renewable generation up to 5% of PG&E's peak load (approximately 1,044 MW of total generation eligible for NEM). Net metering provides a subsidy for customers installing renewable generation at the expense of other customers. As technology costs decline, policy makers should be cognizant of the high cost shift from NEM customers to other customers, especially under today's rate structures.[11] It is not clear that the original impetus for the NEM tariff still exists.

Regarding CHP, there is no basis to conclude that CHP needs such a subsidy. CHP technologies are generally well understood and well established. Therefore, prior to any changes in NEM rules, standby rates, or non-bypassable charges, regulators must first clearly understand the cost shifts and who pays the additional costs. This is especially critical for CHP, which, unlike renewable generation, has the potential to increase GHG emissions.

Question 3: A key feature of AB 1613 is that it allows for export and payment of excess electricity. Will the availability of an AB 1613 feed-in tariff effect your decision to pursue a CHP project in California? Are there any deficiencies in the current implementation of AB 1613? How should they be changed?

Response 3:

PG&E currently offers Assembly Bill ("AB") 1613 feed-in tariff ("FIT") contracts for CHP installations up to 20 MW, with a simpler PPA for installations up to 5 MW. PG&E has filed a simpler PPA with the CPUC for installations up to 500 kW, which is pending CPUC approval. PG&E notes that while the Self-Generation Incentive ("SGIP") is limited to customers who only export up to 25% of their generated power, and there is no such limit on AB 1613 generation, there may be customers who would like to participate in both programs. The SGIP program is designed so that customers can participate in both programs: the SGIP (for at-site offsets) and the AB 1613 FIT (for exports to the grid). The SGIP program will become fully functional when the SGIP Handbook, which will specify the rules for participation, is approved by the CPUC.

There are several issues, in addition to those pending CPUC approval, that remain to be resolved. The major investor-owned utilities currently have no interconnection rule to enable exports to the grid from new QF/CHP facilities under a CPUC-jurisdictional PPA. PG&E and other stakeholders are developing an appropriate interconnection tariff through a CPUC-hosted settlement process. Additionally, the AB 1613 FIT confers the seller's resource adequacy ("RA") value on the purchaser. The CPUC has established an interim process, and a stakeholder process is underway at the California Independent System Operator ("CAISO") to address this issue.

IV. THE IMPACT OF RECENTLY-ADOPTED STATE PROGRAMS MAY NOT YET BE FULLY EVIDENT

Question 1: Comment on the following state programs and their influence on your project if it was available at the time of installation:
• SGIP • AB 1613

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11 See, for example, the Rocky Mountain Institute's paper *Net Energy Metering, Zero Net Energy and The Distributed Energy Resource Future: Adapting Electric Utility Business Models for the 21st Century,* March 2012. http://www.rmi.org/rmi_pge_adapting_utility_business_models

• Rule 21
• Cap & Trade • Other incentives?
Response 1:

A. **SGIP** – To be provided.

B. **AB 1613** – To be provided.

C. **Rule 21** – To be provided.

D. **Cap & Trade** – To be provided.

E. **Other Incentives**

In addition to the SGIP and AB 1613 incentives available for CHP installations, customers installing efficient CHP also enjoy exemptions from some NBCs. CHP facilities up to 5 MW that are eligible for the SGIP program are exempt from the DWR Bond Charge, the Power Charge Indifference Adjustment ("PCIA"), the Energy Cost Recovery Amount ("ECRA"), and the Competition Transition Charge ("CTC") for the first MW of generation. They are also exempt from the New System Generation Charge ("NSGC"), which was established by the CPUC as a non-bypassable charge to implement the Quantifying Settlement ("QF") Agreement.

If the CHP facility is over 1 MW, but meets the definition of "ultra-clean and low emissions" in California Public Utilities ("CPU") Code Section 353.2, the departed load is responsible for the DWR Bond charge, but is exempt from the PCIA, ECRA, and NSGC.

In addition, all CHPs, regardless of size, are eligible for discounted gas rates. They are also exempt from paying for any of the above-market costs of new generation (procurement subsequent to January 1, 2003, including any costs of procuring renewables to meet the state's renewable targets). These costs that CHP avoids are shifted to other PG&E retail customers.

Question 6: What impact do departing load charges have on the viability or operation of your project?

Response 6:
The legislature (and the CPUC) historically established NBCs because of electric industry restructuring (e.g., Nuclear Decommissioning NBC, the Competition Transition Charge to recover the above-market costs of Qualifying Facilities, Public Purpose Program charges) and as a result of the failure of electric restructuring in California (e.g., PCIA, DWR Bond Charge). NBCs were put in place to protect bundled customers who did not have the ability to avoid above-market costs of energy resulting from market failure. Other NBCs have been established to implement policies that were imposed on investor-owned utilities, but not on other load-serving entities (e.g., energy service providers, publicly-owned utilities, community choice aggregators). Again the decision to make certain charges non-bypassable is motivated by a decision to protect remaining bundled customers. Exemptions from departing load charges do

not reduce the cost of the service provided, whether through a PPA or an energy efficiency program. The costs of the service provided are shifted to bundled customers, compromising the purpose of the non-bypassable charge.

Ironically, the costs of many of the price supports that are provided to CHP are recovered through NBCs paid by all customers **other than those receiving the price support.** Specifically, CHP benefits from either above market costs recovered through the CTC defined in the initial restructuring legislation, as well as through the recently approved QF Settlement. Smaller CHP projects that are receiving financial support through the Self-Generation Incentive Program (SGIP) may avoid contributing to the cost of this program if they are on rate schedules where they can avoid paying the distribution costs by offsetting the energy and demand charges.

Question 8: What impact do non-bypassable charges have on viability or operation of your project

Response 8: To be provided.

Question 11: Can your project be dispatched?

Response 11:

There are only a few CHP facilities that have the capability and steam host requirements that allow for the sale of Ancillary Services and the ability to follow Dispatch Instructions as defined in the CAISO tariff. Only if a facility can meet the CAISO's dispatch requirements will it be considered "dispatchable."

In its Tariffs, the CAISO defines dispatch as "the activity of controlling an integrated electric system to: i) assign specific Generating Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage Energy transactions with other interconnected Balancing Authority Areas; and v) curtail Demand. From the utility perspective, to be available for dispatch means that must be capable of participating in any CAISO forward, day-ahead, hour-ahead, real-time or intra-day markets. Appendix A of the CAISO tariff defines a Dispatch Instruction as an instruction by the CAISO "...to a resource for increase its Energy Supply or Demand from the Day-Ahead Schedule, RUC Schedule, and Day Ahead AS Award to a specified Dispatch Operating Point pertaining to Real-Time operations. "

V. TECHNOLOGY INNOVATION TO OVERCOME CHP BARRIERS

Question 1:What is the role of RD&D in advancing CHP and helping achieve the current and future state policy goals related to CHP, such as the AB 32 Scoping Plan and the Governor's Clean Energy Jobs Plan?
Question 2: Which technologies, systems, or component should R&D prioritize to address

some of the barriers to the deployment of CHP? What are some emerging technologies that may be able to address the cost issues associated with CHP?
Question 3:Should RD&D be focused on renewable and fuel-flexible CHP to better help achieve the climate change and renewable portfolio standard goals? What are the major technological barriers to advancing renewable CHP and how can RD&D address those issues?
Question 4: What issues, if any, impede the deployment of CHP into utility territories and how can RD&D help to make CHP beneficial to both the utilities and customers?
Question 5: What other future research direction, strategies or initiatives may be recommended so that RD&D can better help accelerate CHP market deployment?

Response to Questions 1-5:
To be provided.

VI. THE ASSUMPTIONS EMBEDDED IN THE DOUBLE BENCHMARK METHODOLOGY SHOULD BE UPDATED FOR CHP ADDITIONS ABOVE 3,000 MW

The QF Settlement establishes both a MW target for new CHP (3,000 MW) during an initial phase and a GHG emissions reduction target over a longer period (4.3 MMT). The investor-owned utilities will receive credit towards the GHG emissions reduction target for those inefficient CHP resources whose contracts expire.

PG&E would like to highlight a feature of the QF/CHP Settlement Agreement to ensure that it is not misunderstood. The QF/CHP Settlement establishes specific rules designating that PPAs executed on and after September 1, 2009 with existing, new, repowered or enhanced CHP facilities and other QFs of 20 MW and less) count towards the MW target. In addition, contracts entered into as a result of AB 1613 or behind-the-meter CHP facilities also count towards the target.

Question 1: What are the estimated GHG emissions reductions associated with coal-burning CHP facilities with expiring QF contracts? What are the estimated GHG emissions reductions associated with other QFs with expiring contracts that fail to satisfy the double benchmark? What are the aggregate nameplate MW associated with these resources and their dependable (i.e. net qualifying) capacity?
Question 2: Assuming that the utilities are re-contracted with all existing and recently expired QFs that meet the double benchmark, how many MW (nameplate and dependable) would be produced?
Question 3: Has Energy Division staff developed an estimate of the potential range of values for GHG emissions reductions per MW of new (yet-to-be installed) CHP capacity? How many MW of new CHP capacity might be necessary to realize the targeted savings? How does the performance of existing efficient CHP and associated GHG emission reductions compare to the stylized resources implicitly represented in the AB 32 Scoping Plan?

Response to Question 2:

Question 2 refers to the double benchmark in the context of the QF Settlement. PG&E agrees that a double benchmark is necessary. A single efficiency number is insufficient. CHP at 70% to 80% efficiency may sound better than a power plant at 45% efficiency, but it is worse than a new boiler at 92% efficiency. A CHP facility containing a power plant and a new boiler can produce both electricity and steam at an overall efficiency greater than 90% only if virtually all of the fuel is directed to the boiler.

Although a double benchmark is necessary to estimate the GHG emission reductions from CHP, the assumptions should be updated. The QF Settlement was a compromise to settle many issues, and part of that negotiation was a counting procedure to track GHG emissions, with the current embedded boiler and grid electricity efficiency included in the AB 32 Scoping Plan, as the settlement is implemented. The double benchmark assumption may not be appropriate for CHP beyond the amounts in the QF Settlement, for three reasons:

1. Heat Rate: The Settlement used a heat rate of 8,300 Btu/kWh for the grid-based electricity displaced by export from CHP. CEC data on California's gas-fired generation in 2010 (the most recent year available) show an average heat rate of 7,577 Btu/kWh, as noted in PG&E's response to Question I-3 above. Some existing units, termed "aging units" by the CEC, will be retired or repowered over the next several years, which may reduce the average heat rate. Over a time scale of a decade or more, the state-of-the art may improve, as suggested by the new GE FlexEfficiency50 combined cycle, for which the projected heat rate is 5,700 Btu/kWh. As intermittent wind resources are added in future years, new CHP, if not curtailable in off-peak hours, may force displacement of non-fossil resources, which would increase GHG emissions.

2. Thermal Benchmark: The QF/CHP Settlement assumes that thermal output from CHP displaces steam from an 80%-efficient boiler. For CHP beyond the amounts in the Settlement, particularly CHP at new sites, that assumption may not be appropriate. As noted in PG&E's response to Question I-1 above, several manufacturers now offer condensing boilers with efficiencies over 90%. Additionally, some CHP units produce warm water, not steam, for swimming pools and space conditioning. Using a boiler, rather than a water heater, as a benchmark may overstate the GHG emission reductions from CHP units with these applications.

3. Emission Reductions, or Emissions? Emission reductions by their very nature are hypothetical: What would have occurred if the CHP had not operated? In contrast, California's greenhouse gas limit is concrete and measurable—California's goal is to emit no more than 427 million metric tons in 2020. As noted in PG&E's response to Question I-3, compliance will be determined by starting from zero and stacking up measured emissions from all sources, rather than subtracting emission reductions from the level assumed in some reference case. Although CHP can reduce emissions compared to today's power plants and boilers, meeting California's long-term goal—no more than 85 MMT in 2050—may be inconsistent with widespread use of CHP.

VI. PORTFOLIO FIT IS BASED ON A VARIETY OF FACTORS THAT MAY CHANGE OVER TIME

The QF settlement establishes the conditions under which the IOUS may fall short of both the MW and GHG emission targets. Failure to reach MW targets may be justified by a lack of sufficient offers, inefficiency or resources offered relative to the double benchmark, excessive offer prices, and the amount of GHG emissions reductions, but may not be made based on lack of need or portfolio fit arguments. The latter, however, may be used as justification for failure to meet GHG emission reduction targets.

Question 1, Part A: How is the portfolio fit of a prospective resource measured?

Response 1, Part A:

To evaluate the portfolio fit of a prospective resource, first the resource's net market value is calculated. Net market value measures a resource's benefits relative to the resource's costs, irrespective of how well the resource fits into PG&E's portfolio. Benefit components include energy, capacity, and ancillary services. In calculating benefits, inputs may include market data such as forward prices for electricity and natural gas, price volatilities, and correlations, as well as estimated forward price curves for GHG emissions allowances and ancillary services. Inputs also include resource characteristics such as heat rates, generation profile (for resources not dispatchable by PG&E), start-up fuel, minimum up and down times, and other operating characteristics. Cost components include fixed and variable costs, including GHG costs. The difference between benefits and costs is net market value.

Net market value is then adjusted to reflect the value of the resource in the context of PG&E's portfolio. Adjustments include the following elements: how the resource's energy contributes to meeting PG&E's short position in energy and/or exacerbating PG&E's long position in energy, how the resource's capacity contributes to meeting PG&E's short position in Resource Adequacy and/or exacerbating PG&E's long position in Resource Adequacy, how much operating flexibility the resource can provide, and transmission network upgrade costs. PG&E calls the resulting value "portfolio-adjusted value." -

Question 1, Part B: Which attributes of the resource influence its fit into an existing portfolio?

Response 1, Part B:

Location, RPS eligibility, generation profile, and operational flexibility are among the attributes of a prospective CHP resource that affect the prospective resource's portfolio fit.

Question 1, Part C: Which of these attributes have the greatest influence on portfolio fit?

Response 1, Part C:

Which attributes of a prospective resource greatly influence portfolio fit depends greatly on the characteristics of the resource and the portfolio. For example, consider two prospective resources estimated to have the same dollar amount of transmission network upgrade costs but vastly different sizes and electricity outputs. The prospective resource with the greater capacity and greater electrical energy output will have substantially lower transmission network upgrade cost per unit (dollars per MWh or per kW-year). For a much smaller resource to have the same dollar amount of transmission network upgrade costs as a much larger resource suggests that the smaller resource's location and generation profile are greatly influential on portfolio fit.

Similarly, how a prospective resource's attributes influence portfolio fit changes over time. One factor likely to become increasingly important is operational flexibility. California law and policy support continual development of renewable electricity resources, including some that have intermittent output. Integrating these resources, while matching overall supply to meet instantaneous demand, will increase the need for operational flexibility from PG&E's portfolio. For example, as the amounts of off-peak electricity from wind turbines increase, portfolio fit decreases for a prospective resource with non-curtailable, "must-take" electricity, while portfolio fit increases for a prospective resource that offers significant operating flexibility.

VII. QUESTIONS FOR CHP REPRESENTATIVES

The standard planning assumptions in the 2010 LTPP included continued operation of existing CHP, and 1,872 MW of new CHP (1,522 MW in the IOU service territories) that operates at very high capacity factor and evenly divides its output between on site uses and export.

Question 1: Are existing QF resources that meet the double benchmark likely to be more or less competitive than new projects in CHP RFOS?

Response 1:

Existing QF resources that meet or exceed the double benchmark are expected to be more competitive than new projects in the first program period CHP RFOs, when the IOUs may be more focused on the MW targets. This results from there being no development or construction risk associated with an existing project, whereas a new project could be subject to numerous delays or cancellation during the development process. The availability of a 12-year PPA for new or repowered facilities allows amortization of new investment over a longer period, and may partially offset this possible disadvantage.

Question 3: What conditions are/might be necessary to realize this quantity of new CHP? What is the likely impact of failing to get a long-term contract for exports on development?

Response 3:

A new CHP facility sized 20 MW or less may sign the pro-forma PPA for PURPA facilities of 20 MW and Under, with a maximum term of 12 years, if it meets the PURPA efficiency standard. It may also sign the AB 1613 PPA, with a maximum term of 10 years, if it meets the CEC's AB 1613 efficiency standard. Gas-fired CHP facilities with nameplates greater than 20 MW, but with average annual deliveries less than 131,400 MWh, subject to Public Utility Code efficiency requirements are eligible for the maximum seven year pro-forma As-

Available PPA. The QF/CHP Settlement Agreement requires each IOU to procure an allocated portion of the Settlement's new CHP MW procurement target. Steady progress toward the July 1, 2015 goal is assured by apportioning each IOU's allocation into three targets, to be achieved through competitive solicitations for CHP generation, before the July 1, 2015 deadline. PG&E cannot speculate on the effect of a project's failure to obtain a long-term power purchase agreement on the development of any single project, nor on the achievement of any industry goals. Prior to considering what conditions are necessary to achieve other levels of installations, the CEC should consider the need for resources, the generation attributes needed, and the cost.

Question 4: If large quantities of new CHP are developed, is the assumption of a 50/50 split between on-site use and export a reasonable one? If not, what might a more reasonable split be?

Response 4:

Based on the recently released draft ICF study and the current design of the SGIP program incentives, the 50/50 split generally does not work. It is too high for the smaller-sized CHP facilities. SGIP only allows exports of up to 25% of the total generation, and the ICF report shows zero exports for installations up to 1 MW and only modest exports for installations up to 5 MW. The 50/50 split is too small for larger facilities, based on the ICF draft report showing 3,847 MW of exports for the total of 4,679 MW technical potential for existing facilities (82% exports) and 131 MW of 215 MW for new facilities (61% exports).

VIII. REASONABLE PLAN FOR FUTURE CHP DEVELOPMENT

Question 1: What is a reasonable planning assumption (single point or range) for the peak capacity value of CHP development during 2013 – 2022?

Response 1:

In PG&E's 2010 Long-Term Procurement Plan, Track 2 (standardized assumptions) at the CPUC, and in PG&E's filing to the CEC in the 2011 IEPR proceeding, the nameplate capacities shown below were provided.

New CHP MW (Nameplate) by 2020

	Standardized Assumptions	IEPR
Demand Side CHP (non-exporting)	373	314
Supply Side CHP	409	174

IX. ECONOMIC ACTIVITY AND ITS EFFECT ON CHP DEVELOPMENT

Question 1: What additional analysis can complement the work completed to support

changing CHP development regulations and goals? (i.e. GHG emissions comparison to displaced technologies, etc.)

Response 1:

There is considerable uncertainty about the ability of large amounts of CHP to meet the required efficiency criteria and improve upon the emissions of using a boiler and electricity from the grid. PG&E recommends that the CEC examine the "double benchmark" and relevant input assumptions to determine the appropriate comparison for CHP and GHG reductions. Additionally, to inform understanding of CHP potential, the CEC should revisit the reporting guidelines of useful thermal output reported by CHP facilities in the Energy Commission Quarterly Fuels and Energy Report (QFER) so that generators report better quality information more consistently.

Form 1304 reporting should require all CHP facilities to report fuel input, net electrical output, and used heat output. All values should be reported in units of million British thermal units (MMBtu). Taken together these three values will provide accurate CHP operating efficiency information. PG&E provides its detailed suggested change to *Form CEC-1304 Schedule 1, 2, and 3 – Power Plant Generation and Fuel Quarterly Reports with Annual Environmental Information Instructions* as Attachment A to this document.

Question 2: Should the state create incentives or penalties to ensure achievement of targets? If so, please suggest program design and implementation.

Response 2:

Without additional insight into the questions outlined above, discussion of incentives is premature. Additionally, new opportunities for CHP have been advanced through AB 1613 feed-in tariffs, through SGIP rules, and QF/CHP settlement RFO activities. These policies should be fully deployed and evaluated for impact before creating even more new incentives and policy.

Question 3: What are the near-term and long-term actions needed to achieve 6,500 MW by 2030?

Reponse 3: To be provided.

Question 4: What additional steps could the state take to encourage further development? Prioritize and explain.

Response 4: To be provided.

Question 5: What market opportunities exist for bio-powered CHP?

Response 5: To be provided.

Question 6: What challenges limit the penetration of bio-powered CHP at existing facilities, such as waste water treatment plants or food processing facilities?

Response 6: To be provided.

Question 7: What can the Energy Commission, or the state, do to increase market penetration of bio-powered CHP?

Response 7: To be provided.

Question 8: What can be done from a regulatory standpoint to reduce uncertainty for CHP development?

Response 8: To be provided.

Question 9: What is the potential development of CHP that could be classified as renewable? What are the major regulatory barriers to renewable CHP development and how can they be addressed?

Response 9: To be provided.

Question 10: AB 1613 also encourages utilities to take advantage of CHP. Will utilities take advantage of this opportunity? If not, why? What would it take?

Response 10: To be provided.

Question 11: Utilities have had a role in CHP development in the past. Is there a role for CHP in the utility portfolio and what role would it play? What interest do utilities have in the development of CHP? What incentives are necessary?

Response 11: To be provided.

IV. CONCLUSION

PG&E looks forward to continuing discussion of combined heat and power issues in the 2012 IEPR.

Sincerely,

Valerie J. Winn

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Attachment A: Suggested Changes to Form 1304 Schedule 1, 2, and 3 – Power Plant Generation and Fuel Quarterly Reports with Annual Environmental Information Instructions[1]

On page 6 we suggest the following change:
"For each cogenerator, enter the following ….

4. ~~**Fuel Attributable to Useful**~~ **Used Thermal Output (MMBTU)**. The amount of ~~primary fuel attributable to useful~~ thermal output used in some process. ~~Due to the wide variety of useful thermal processes available to cogeneration plants, assume 100% conversion of fuel to useful thermal."~~

Explanation:

1. Reporting requirements can be simplified, given each CHP facility already reports fuel input in MMBtu, and reports net electric output in MWh, which can easily be converted into MMBtu. If CHP reports used thermal output in MMBtu, calculating waste heat is simple.
2. As an alternative to used thermal output in MMBtu, CHP could report output in lbs/year of steam or hot water at some temperature. (Any return flows should be noted, too.) The CEC could then calculate MMBtu of used thermal output.
3. Possible Addition: Ask for the nature of the thermal output (steam or hot water) in order to select the appropriate boiler or hot-water heater for GHG-reduction calculations.

[1] Available from: http://www.energy.ca.gov/forms/instructions/1304_Instructions.pdf